Evaluating the benefits of an electrical energy storage system in a future smart grid☆

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Abstract

Interest in electrical energy storage systems is increasing as the opportunities for their application become more compelling in an industry with a back-drop of ageing assets, increasing distributed generation and a desire to transform networks into Smart Grids. A field trial of an energy storage system designed and built by ABB is taking place on a section of 11kV distribution network operated by EDF Energy Networks in Great Britain. This paper reports on the findings from simulation software developed at Durham University that evaluates the benefits brought by operating an energy storage system in response to multiple events on multiple networks. The tool manages the allocation of a finite energy resource to achieve the most beneficial shared operation across two adjacent areas of distribution network. Simulations account for the key energy storage system parameters of capacity and power rating. Results for events requiring voltage control and power flow management show how the choice of operating strategy influences the benefits achieved. The wider implications of these results are discussed to provide an assessment of the role of electrical energy storage systems in future Smart Grids.

Keywords: Active networks, Electrical energy storage, Power system modelling.

1. Introduction to energy storage

Electrical energy storage systems have been in use since at least 1870 when Victorian industrialist Lord Armstrong built one of the worlds first hydroelectric power stations at Cragside in Northumberland, UK (Bowers, 1982). In hydroelectric schemes, the penstock valve regulates the conversion of potential energy held by water in an upper reservoir into electrical energy by a turbine-generator set. The storage capacity of a scheme is determined by the volume of water available in the reservoir and the power output by the rating of the generator (Sørensen, 2004). In the middle of the twentieth century power systems rapidly changed from isolated networks with local generation and load, to a fully interconnected national system with transmission of bulk generated electricity to passive distribution networks (Lehtonen and Nye, 2009). This suited the favoured primary energy sources at that time, initially coal and oil, then later nuclear and gas.

Electricity distribution networks have entered a period of considerable change, driven by several interconnected factors; ageing network assets, installation of distributed generators, carbon reduction targets, regulatory incentives, and the availability of new technologies (Bouffard and Kirschen, 2008)(Scott, 2004). In this climate, the use of distributed storage has re-emerged as an area of considerable interest. The end of this period of transition will be signalled by the successful establishment of the technology and practices that must go together to create what is termed the Smart Grid. The UK Electricity Networks Strategy Group (ENSG) provide a useful definition of the term Smart Grid (ENSG, 2009):

> A Smart Grid as part of an electricity power system can intelligently integrate the actions of all users connected to it generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.

The precise end state of this transition is not yet known, one possibility is outlined up to 2050 by the ENSG in 'A Smart Grid Routemap' (ENSG, 2010).

The need to investigate the role of electrical energy storage has been identified at governmental level. The Parliamentary Renewable and Sustainable Energy Group (PRASEG) inquiry into 'Renewables and the grid: access and management' cites storage as a 'possible solution for addressing variable renewable energy generation' and highlights the need for 'Long- term, further research and development' and 'clear political and regulatory signals' (PRASEG, 2010). In the UK Low Carbon Transition Plan (Government, 2009) storage is included in the list of key elements of a UK smart grid. To enable new solutions

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and technologies to be developed the UK regulator the Office of the Gas and Electricity Markets (Ofgem) has made the 500M Low Carbon Networks Fund available to 'help all DNOs [distribution network operators] understand what they need to do to provide security of supply at value for money as Great Britain (GB) moves to a low carbon economy' (Ofgem, 2010). Although separate LCNF projects will be run by the 14 DNOs that operate in GB, the use of this funding mechanism brings with it a requirement to disseminate the findings to all concerned parties.

It was identified as early as 1959 that to make best use of renewable energy resources with a meteorologically dependent output, a storage element to the overall system would increase the energy yield (Giacoletto, 1959). As well as increasing yield, the ability to add dependability to renewable resources has been widely investigated (McDowall, 2005)(Paatero and Lund, 2005)(Sørensen, 1976). When distributed generation is added to the extremities of the distribution network, a change to the voltage profile along the conductor carrying the current (commonly called a feeder in distribution networks) can limit the amount of power that can be transferred by the network. Solutions have been implemented that modify the automatic voltage control (AVC) settings at the primary substation to increase the sophistication of voltage management across all the feeders on the network such as Fundamentals SuperTAPP n+ and Senergy Econnects GenAVC (Fila et al., 2008). Energy storage has the potential to achieve a less invasive intervention, largely acting on only a single feeder, as has been explored by several authors (Arulampalam et al., 2006) (Barton and Infield, 2004) (Tande, 2000).

Aside from being of benefit to distribution systems with distributed generation, energy storage can be applied more generally to assist with and improve network operation. The injection of ideal combinations of real and reactive power for voltage support and loss reduction was assessed by Kashem and Ledwich (2007). Oudalov et al. (2007) concluded that a lead-acid based storage system could at present provide a profitable solution for primary reserve capacity for frequency control. A similar result was found for isolated power systems (Mercier et al., 2009). The value of electrical energy storage for the purposes of energy arbitrage, frequency regulation and network reinforcement deferral was calculated for the New York system by Walawalkar et al. (2007). The authors concluded that sodium-sulphur (NaS) and flywheel units had a high probability of a positive net-present value in the New York City region for energy arbitrage and frequency regulation. The role of energy storage has been evaluated by Black and Strbac (2007) for a scenario where a 20% share of total UK demand is met by many large wind parks. They conclude that energy storage has a role in managing short-term fluctuations in aggregate wind output, but traditional standing reserve provides the most economical solution to longer variations. These examples highlight some areas in which energy storage is considered to have potential for commercial exploitation in different markets; the analysis in this paper is of the technical benefits that can be achieved on a GB distribution network, which can then feed into market assessments.

The ability of an Energy Storage System (ESS) to transfer real power is limited by the installed storage capacity. An operating regime could follow a pre-defined cycle of charging and discharging that is known to be within the bounds of the device. A more sophisticated approach is to determine the prevailing network conditions from strategic measurements, and provide an appropriate response from the ESS. In this approach the demands put on the storage capacity cannot be known with certainty in advance. The inherent risk of a shortfall in capacity requires a collaborative and coordinated sharing of the control task between several actions, such as storage, generator curtailment and load control. Coordination of several elements of control on the distribution network has been investigated in projects such as by the distribution management system coordinated controller proposed by Bignucolo et al. (2008).

There is plentiful literature on the technologies now available and under development for electrical energy storage. Divya and stergaard (2009) provide a review of alternative battery types and give examples of applications in which they are in use. Hall and Bain (2008) compare a broader range of storage technologies, including flywheels and superconducting magnetic energy storage. Future advances that are expected in energy storage systems are examined by Baker (2008). Additional examinations of storage technologies (Carrasco et al., 2006) (Ribeiro et al., 2001) contribute to a broad coverage of the topic.

2. Summary of benefits from energy storage

The GB electricity supply chain is deregulated and has clear divisions between generator companies, the transmission system operator (TSO), distribution network operators (DNOs) and supply companies. Application of energy storage to distribution networks can benefit the customer, supply company, DNO, TSO and generation operator (conventional and DG) in several ways. Opportunities for stakeholders in the electricity value chain were analysed by Delille et al. (2009) in the context of the French distribution system and island networks. A series of reports from Sandia National Laboratories assesses the cost-benefit of transmission and distribution upgrade deferral (Eyer, 2009), and power quality, arbitrage and generation capacity credit (Schoenung and Eyer, 2008) in the US. Fourteen separate benefits are evaluated in the Sandia Labs Energy Storage Benefits and Market Analysis Handbook (Eyer et al., 2004). Drawn from a survey of the above literature, the areas where energy storage systems can be applied can be summarised as:

- Voltage control; support a heavily loaded feeder, provide power factor correction, reduce the need to constrain DG, minimise on-load tap changer (OLTC) operations, mitigate flicker, sags and swells.

- Power flow management; redirect power flows, delay network reinforcement, reduce reverse power flows, minimise losses.
- Restoration; assist voltage control and power flow management in a post fault reconfigured network.
- Energy market; arbitrage, balancing market, reduce DG variability, increase DG yield from non-firm connections, replace spinning reserve.
- Commercial/regulatory; assist in compliance with energy security standard (ER P2/6) (Association, 2006), reduce customer minutes lost (a GB regulatory incentive designed to improve quality of service) (Ofgem, 2005), reduce generator curtailment.
- Network management; assist islanded networks, support black starts, switch ESS between alternative feeders at a normally open point.

It is evident in the literature that developing a compelling business case for installing an energy storage system at distribution level in the current electricity market with present technology costs will be difficult if value is accrued from only a single benefit. The importance of understanding the interactions between several objectives and quantifying the benefit brought to each of them is a critical activity in evaluating the potential of electrical energy storage.

This paper reports on research that has addressed the need for the development of techniques that will enable the benefits brought from ESS operation to be assessed. In the next section the energy storage field trial project to which this work relates is introduced. This is followed by a description of the methodology used to evaluate the use of electrical energy storage on distribution networks. Results from several simulations then illustrate how the choices made in configuring and operating an ESS impact on the performance. The results are discussed and lessons are set out along with observations on the implications in the wider application of energy storage.

3. Field trial of energy storage

A project trial conducted by EDF Energy Networks, ABB and Durham University is evaluating the use of energy storage on distribution networks. This began as one strand of the AuRA-NMS Strategic Partnership between the Engineering and Physical Sciences Research Council (EPSRC), ScottishPower Energy Networks, ABB and EDF Energy Networks (Davidson et al., 2009, 2008). Ongoing work focussing on the deployment of the storage system was the first project to register in the UK regulators (Ofgem) Low Carbon Network Fund (LCNF) as a First Tier project (Networks, 2010). This funding mechanism stipulates public dissemination of project findings, so there is potential for this work to influence DNO policies on energy storage.

In the summer of 2010 an energy storage system (ESS) designed and built by ABB will be installed on an 11kV distribution network in the East of England. The ESS consists of a lithium-ion battery array coupled to ABBs SVC Light (a static VAr compensator or STATCOM) and control system. The ESS has been placed at a normally open point (NOP) to allow connection to either one of two sections of network fed from different primary substations as shown in Fig. 1. Distribution networks are designed with many NOPs between different areas of the network to give control engineers the capability to reroute power flows under fault conditions or during routine maintenance. Some underground cable but predominantly overhead line forms the network with a maximum length of 5 km. The loads served by the feeders are a mixture of farming, light industrial, residential and holiday accommodation and it is useful to note that the feeders exhibit demand profiles that contrast with each other on a diurnal and seasonal basis. Demand on each feeder averages 1.15 and 1.30 MW and peaks of 2.3 and 4.3 MW have been recorded. A 2.25 MW wind farm with fixed speed induction generators is attached midway along one feeder.

The ESS has a storage capacity of 200 kWh and a power electronic converter capable of sinking or sourcing power of 600 kW and 600 kVAr simultaneously. The minimum, modal and maximum demand on the feeders is 0.6, 1.2 and 4.3 MW respectively. In this test installation, the energy capacity of the device will only provide power of a significant proportion of the peak network power flows for short periods. However, interventions of a smaller magnitude also have benefits and can be sustained for longer durations. The choice of device size was a balance between ensuring measureable interventions can be made and keeping costs in proportion for what is an experimental system. Given the time-limited nature of the resource, this study is in part designed to determine the best outcome that can be achieved within the operating parameters of the device.

In the course of this research, a framework for evaluating the use of electrical energy storage systems on distribution networks has been developed. Steady-state analysis of an electrical network model loaded with values from historical operational data sampled at 30-min intervals combined with an ESS model and control algorithm, simulate distribution network operation over a period of one year. An event is considered to have occurred when a specified measurement on the network (typically, but not limited to, voltage or power flow) crosses a defined threshold. Multiple events on multiple networks have been tackled simultaneously by operating an ESS to modify real and reactive power flows to the benefit of the network. Summary data has been compiled to quantify the benefits accrued from operating an ESS and identify best practice.

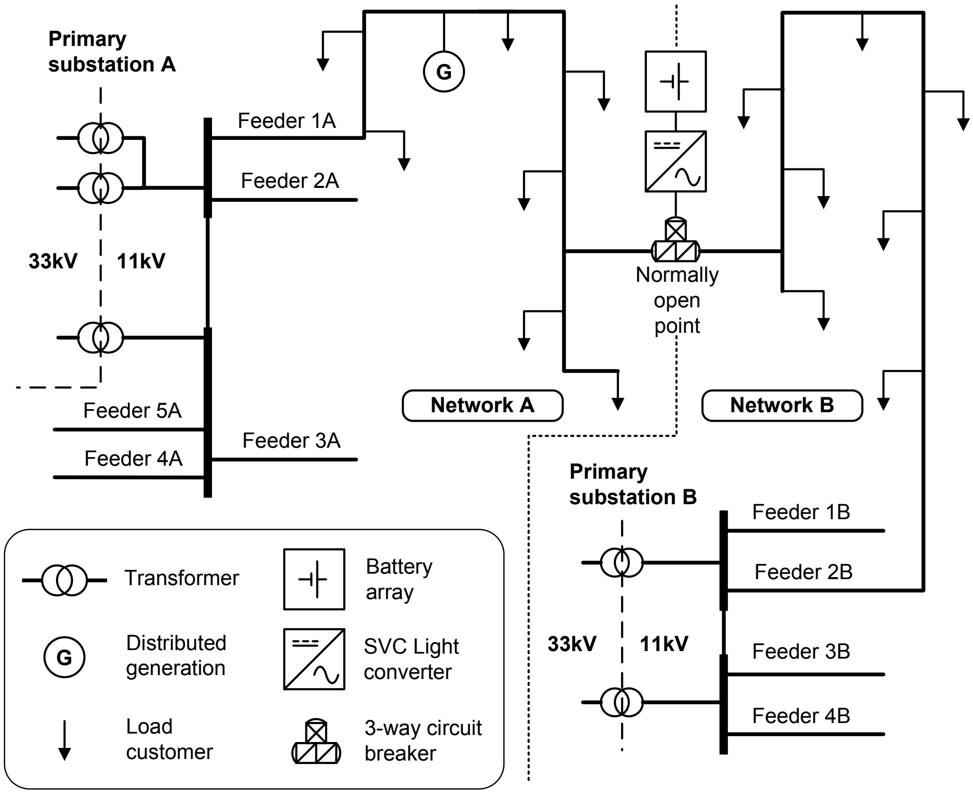

Figure 1: Field trial network diagram showing two feeders and location of ESS at the normally open point. The position of a windfarm on Feeder 1A is indicated by the letter G.

4. Simulation methodology

4.1. Network modelling

At the centre of simulation software is a control algorithm that follows deterministic rules to manage operation of the ESS. Information processed by the algorithm comes from measurements of the network state and internal registers which retain the prior actions of the ESS. The algorithm ensures that the capabilities of the ESS for both power rating and energy capacity are never exceeded. Decisions on when to switch the ESS between feeders and battery management are reached by following rules in the algorithm.

Historical data for the networks on which the installation is taking place was provided by EDF Energy Networks at a 30-minute resolution covering a period of several years. Data included power flows on each feeder and DG output, which when put together allows the customer demand to be calculated and network power flows and voltages to be reconstructed by load flow analysis. Although there is a risk when using real data of errors and atypical occurrences, the selected dataset was chosen because it was recent, almost entirely intact and typical in comparison with complete multi-year dataset.

IPSA+ power system analysis software provided the load flow capability (?). A model of the network was built with detail of transformers and conductors from the 33kV connection point to the level of distribution transformers on the feeders to which the ESS can be connected. On the other feeders the demand was represented by a lumped load for each feeder. IPSA+ provides an interface to the Python programming language, which enables automated control of the network model and load flow engine. This functionality was used to provide the control algorithm with measurements of the network state.

Automatic voltage control (AVC) is used to stabilise a primary substations busbar voltage by adjusting the transformer winding ratios in response to variations in the incoming voltage and the load supplied. Load is determined from transducers measuring the current on each of the outgoing feeders from the substation. The presence of distributed generation on a feeder causes a reduction in current and this is interpreted as a reduction in load by the AVC. This behaviour was not considered in the design of such voltage control schemes and it has been found that it is better to exclude feeders with distributed generation attached from contributing to the determination of voltage set-points (Collinson et al., 2003). This prevents the reduction in demand on a feeder due to local consumption of distributed generation from causing the remote ends of other feeders to fall below the statutory voltage limit. In the field trial network, the feeder with energy storage (Feeder 1A in Fig. 1) and one other feeder from the same primary substation are excluded from the AVC due to DG schemes, leaving the combination of currents on the three remaining feeders to dictate the AVC target voltage. This behaviour is incorporated into the set up of the network simulation.

The ESS is modelled in the network as a combination of load and generator, both of which can operate with a power factor from zero to unity. In this way the ESS device can sink and/or source real and/or reactive power in any combination within the rating of the system. Although reactive power up to the rating of the power electronic converter is always available, the duration of an action using real-power is a function of the power level and limited by the capacity of the battery. Any time the battery is not in the preferred waiting state-of-charge, power will be exchanged with the network to adjust the battery condition, unless this process would cause the network to move into an undesirable state.

The components of control algorithm, historical network data, network model, load flow engine and ESS model were combined to conduct a simulation of the system every 30 minutes for a period of one year. Data was recorded at each simulation interval to characterise the changes in voltage and power flow in terms of maximum values, minimum values and distributions. By altering parameters within the control algorithm in several simulations, comparisons were made between alternative operating strategies.

4.2. Choice of objectives

In 'A Smart Grid Vision' the ENSG conducted a cost-benefit analysis to identify the value of several improvements that can be brought about through investment in a Smart Grid (ENSG, 2009). The highest two discounted value benefits were given to Voltage Optimisation and Demand Response, followed by Asset Management, Losses, Distributed Generation, Outages and Capacity Planning. At an early stage of researching the application of energy storage at distribution level, it was identified that there was a capability to measurably influence voltage and power flow. The importance attributed to voltage optimisation and demand response combined with the ability to influence them, led to the selection of voltage control (VC) and power flow management (PFM) events for detailed evaluation in this study.

Events were chosen to test the ability of the ESS to bring about improvements to voltage levels and power flow. When installed this will be a live project on a real network, so the choice of targets must be able to be applied in reality, show a measurable change in network behaviour and not cause adverse effects on normal operation of the network.

Events are defined by type, threshold, location and action. The type of event describes what is being monitored on the network, four event types are considered here; over-voltage, under-voltage, over-power and reverse-power-flow. Thresholds were decided through two considerations; the number of events generated during the simulation year and how feasible it is to address those events with the given power and energy ratings of the ESS. The choice made for each event is detailed below. Location determines where the measurement is taken. The final parameter instructs what action should be taken in response to the occurrence of an event beyond the threshold at the specified location; this can use the four-quadrant capability of the power electronic interface to give any combination of sinking and/or sourcing of real and/or reactive power.

4.3. Voltage control

Voltage improvements were tested by setting a target band narrower than that recorded during network simulation without the intervention of the ESS. Two events were defined to set the upper and lower limits of the band; over-voltage and under-voltage. Since both events cannot occur at the same time, they can never be in competition for resources from the ESS. The details of voltage targets set on both networks can be seen in Table 1, along with the targets for the events described below.

4.4. Power flow management

Network A has a windfarm connected mid way along the feeder. A useful proxy to indicate the match between the windfarm output and load demand is the power flow at the point the feeder leaves the primary substation. In situations where the current is flowing back into the substation, there is more generation output than can be absorbed by the local demand. There are several reasons why this might be an unfavourable situation; with high penetrations of DG, aggregation of generator outputs could lead to reverse power flows through the transformers and on-load tap-changer (OLTC) equipment onto the 33kV network, there are limits to the extent this is permissible in some cases due to the design of the OLTC (Cipcigan and Taylor, 2007). Even if this technical limitation does not exist, high levels of DG connection at 33kV and above can lead to congested networks into which further injections of power with only modest magnitude will cause over-loads. Energy transferred away from the local load will have to be returned later in time; local storage would relieve the distribution network when the peak demand occurs. Reverse power flow can occur with considerable magnitude, so it is not practical or indeed necessary to eliminate all reverse flow. A threshold was determined that balanced the number of events with the ability to respond and in this case reverse power flows greater than 0.4 MW were selected which gave approximately 600 events to act on. In response to a reverse-power-flow event the ESS action is to sink real power, redirecting DG output power downstream from the primary substation.

Network B has no DG connected so power flow is unidirectional to the load. Reduction of peak power flows was selected as an event for this feeder. The location for measuring power flow was chosen to be the conductor operating closest to its thermal capacity. Action was taken when power flow exceeded the specified threshold. Approximately 800 events are generated throughout the year.

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Network	Type	Threshold	Location	Action	Annual Event Count
A	Over-voltage	2.5%	ESS	Sink Q	71
	Under-voltage	-1.0%	ESS	Source Q	914
	Reverse-power	-0.4 MW	Primary sub	Sink P	579
B	Over-voltage	3.6%	ESS	Sink Q	40
	Under-voltage	0.8%	ESS	Source Q	563
	Over-power	49%	Thermal capacity	Source P	812

Table 1: Summary of event definitions.

An over-power event is counteracted by the ESS sourcing real power, thereby reducing the power that needs to be supplied from the primary substation.

4.5. Structure of simulations

The hierarchy of simulation configurations is shown in Fig. 2; four simulations assessed the events in isolation, two simulations were required to cover each network with multiple events and one simulation tested all events on both networks. It was necessary to run simulations with only one event and then multi-event simulations on a single-network to provide a comparison between each approaches. Once more than a single event is to be considered by the control algorithm, an appreciation of the timing and severity of each event is required to ensure that decisions are taken that make the best use of the finite resources of the ESS. With the events chosen in this simulation, there were contrary requirements for the waiting state-of-charge from the real-power based actions associated with the reverse-power-flow and over-power events. Network A required the battery to be discharged ready to sink real-power, while Network B needed charge available to be sourced during over-power conditions. Through analysis of the time-of-day of events, opportunities were identified for adjusting the waiting state-of-charge to be ready to deal with the greatest number of events overall. This approach used previous experience as a primitive forecasting technique; further gains would be accrued from a more sophisticated forecasting technique, making use of meteorological and demand prediction information.

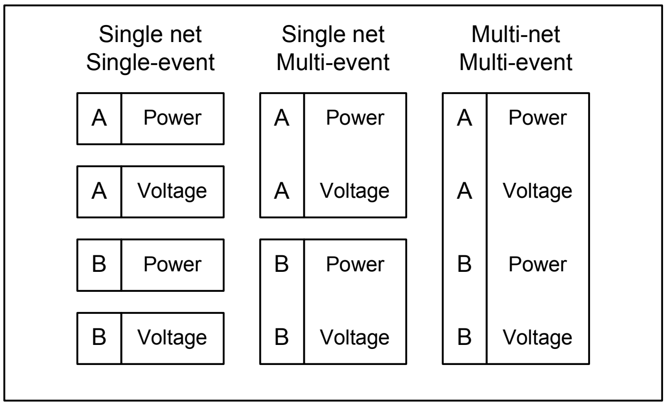

Figure 2: Identification of the configuration of simulations with respect to events and networks. Each box corresponds to one annual simulation run.

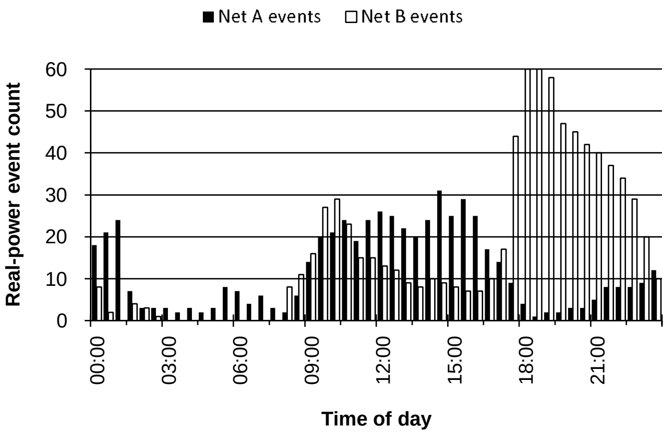

Figure 3: Daily distribution of reverse-power-flow events on Net A and over-power events on Net B with no ESS intervention.

5. Results

Before any interventions are made by the ESS, it is necessary to establish the count of each event under consideration. At each sampling point in the year, separated by 30-minute intervals, the network is either in- or out-of-limit with respect to the target event. To present the event count in a more meaningful way than can be achieved from a single number, any out-of-limit events that occurred at each of the 48 sampling points during the day were summed across the year of simulations. This process reveals the diurnal distribution of out-of-limit events experienced on the network. Although not giving detail of the specific day on which events occur, Figs. 3–5 give a strong indication of how well the time-of-day of events under consideration complement each other. Fig. 3 shows that real-power events on Network B occur predominantly from 17:00 to 00:00, at which time Network A has a relatively low requirement for support. Network A has two periods during the day that cover the majority of event occurrences; from 00:00 to 01:30 and 09:00 to 17:30. This observation informed the adoption of a time-of-day state-of-charge balancing (TSB) approach that sets the waiting state-of-charge at a specified time-of-day to suit the requirement from the network with the greatest likelihood of an event occurring. This is implemented by charging the battery at 16:30 in readiness for over-power events on Network B and discharging from 23:00 to be available for reverse-power events on Network A.

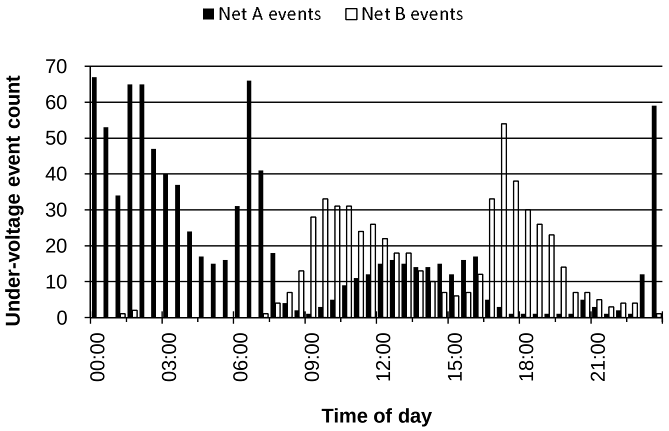

Figure 4: Daily distribution of under-voltage events on Net A and B with no ESS intervention.

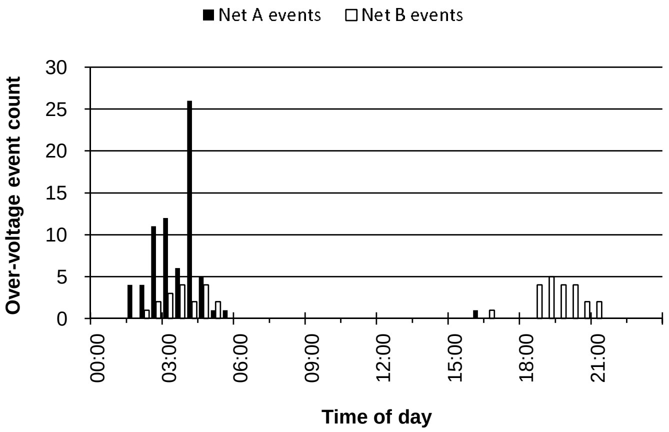

Figure 5: Daily distribution of over-voltage events on Net A and B with no ESS intervention.

Considerable complementarity can be seen for under- and over-voltage events in Figs. 4 and 5. The reactive power used to intervene in these circumstances is generated by the power electronic converter switching an integral capacitor bank and is independent of the energy stored in the battery. There is therefore no requirement to alter the state-of-charge in readiness for these events, but the result does give confidence that there will be minimal ESS resource conflict between networks.

5.1. Performance metrics

Two measures of the degree of success due to the ESS actions are presented. If action by the ESS causes the event to move below the threshold set point, then the event is considered to be solved. For power events there is a quantity of energy associated with an event which will be reduced by ESS action even if the event is not solved. As an example, take a situation when reverse-power-flow is running at 0.73 MW. Action by the ESS may only reduce this quantity to 0.53 MW, so does not cross the 0.4 MW threshold but a significant improvement has been made nonetheless. As part of a coordinated approach, further improvements to the situation would be handled by other techniques; in this case DG curtailment could be used. Conversely, a very small reverse power flow of 0.43 can be solved with only a small magnitude ESS action.

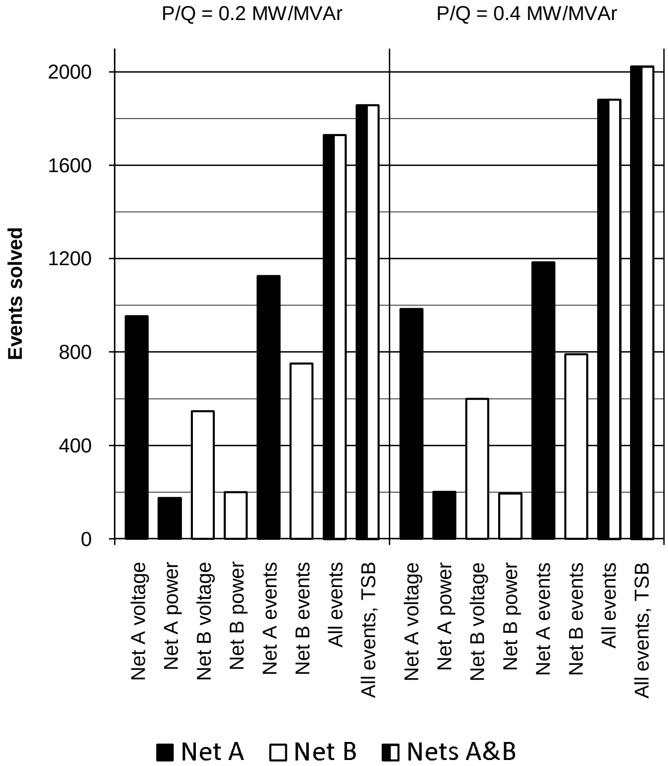

Figure 6: Variation in number of events solved depending on configuration of simulation and converter rating.

The measure of events solved in Fig. 6 shows results for all the network configurations described in Fig. 2, with maximum allowed power ratings of 0.2 MW/MVAr on the left and 0.4 MW/MVAr on the right. Black bars indicate configurations operating on Net A, white bars on Net B, while the black and white bars show configurations operating on both Net A and B simultaneously. This choice of ratings is not intended as an investigation into the optimum sizing of a storage system; but working within the limits of the field trial system, these alternative ratings illustrate the change in outcome due to the maximum power rating of the power electronic converter in the ESS. The converter rating could be set by the electrical design characteristics of the device, or be an artificial limit imposed to suit a preferred operating strategy.

Several features can be observed for both power ratings:

- The number of voltage events solved is considerably greater than power events.
- Moving from single event to single network configuration yields a total of events solved close to the sum of those events solved as single events.

- When time-of-day state-of-charge balancing (TSB) is used, a significant improvement is seen over the configuration of multi-network with fixed waiting state-of-charge.

An increase in the number of events solved is seen for all configurations when the maximum allowed power is increased from 0.2 to 0.4 MW/MVAr. This effect is most pronounced in the multi-network configurations. Operating with TSB makes use of knowledge gained from analysis of historical data to stipulate a time-of-day when the state-of-charge is adjusted. Advantage is taken of the temporal differences between the defined events on the two networks, which are seen in Figs. 3–5. Such a technique will work on networks with sufficient complimentarity, and in this case when operating in multi-network configuration with TSB, the number of events solved is greater than the sum of multi-event operation on Network A and Network B. This can be interpreted to mean that in this situation it is better to use one ESS in collaboration between networks than to operate two ESSs independently with one on each network.

Magnitude improvements in reverse-power-flow events on Network A and over-power events on Network B in Fig. 7 give further insight into the subtleties of configuration changes and maximum allowed power. Single-network configurations at 0.2 MW/MVAr produce similar reductions in energy associated with each event. When the power is increased to 0.4 MW/MVAr, although improvements in event count were seen, the associated energy falls when moving to a multiple-event configuration. The gains from operating multi-network with TSB are more pronounced than when simply considering the number events solved. The ability to shift energy between feeders goes some way to address the limitation of finite battery capacity. Consider a situation where an event is occurring continuously for an extended period of time, if there is no ability to switch to an alternative feeder, when the battery capacity is reached the ESS can only wait until the network state has returned within limits to attempt to return the battery to the state-of-charge required to tackle the event. If it is possible to switch the ESS over to another area of network, which is either in a normal state or would benefit from the transfer of power required to adjust the battery state-of-charge, then after this operation the ESS can be switched back to the original network and again provide the necessary support for the ongoing event. The underlying reason for tackling an event may be either essential or preferable, the period of time when the ESS is unable to intervene due to the state-of-charge adjustment taking place would be tackled by another control measure in the first instance or could be left untouched if resolving the event is only preferable.

Improvements in voltage performance are quantified by the furthest deviation from the edges of the target band in Table 2. All deviations on Network A are eliminated with 0.4 MVAr of reactive power available. At the same power level, Network B over-voltages are out-of-band by 0.09% for all simulation configurations, while under-voltages are fixed when operating as a single network but a conflict arises in multi-net configuration causing a 0.33% deviation. At 0.2 MVAr some deviation remains in all cases, on Network A a slightly better result is seen when configured to tackle a single event. Network B sees the best result when configured to tackle both voltage and power events, the improvement on the single event case is due to a synergy between the under-voltage and over-power events whereby solving over-power events tends to improve under-voltage events concurrently. The relative ability of the transfer of real or reactive power to affect a change in voltage is determined by the properties of the conductors in the network. Unlike transmission systems where the dominance of the reactance of conductors means that voltage magnitude is almost exclusively controlled by reactive power exchanges, distribution system conductors have a ratio of reactance and resistance typically much closer to unity. In this situation real power flow influences voltage to a much higher degree. Synergies such as this observed for voltage have not been explicitly sought after, but it should be noted that further improvements to control algorithms should consider the gains that can be obtained in this and similar ways.

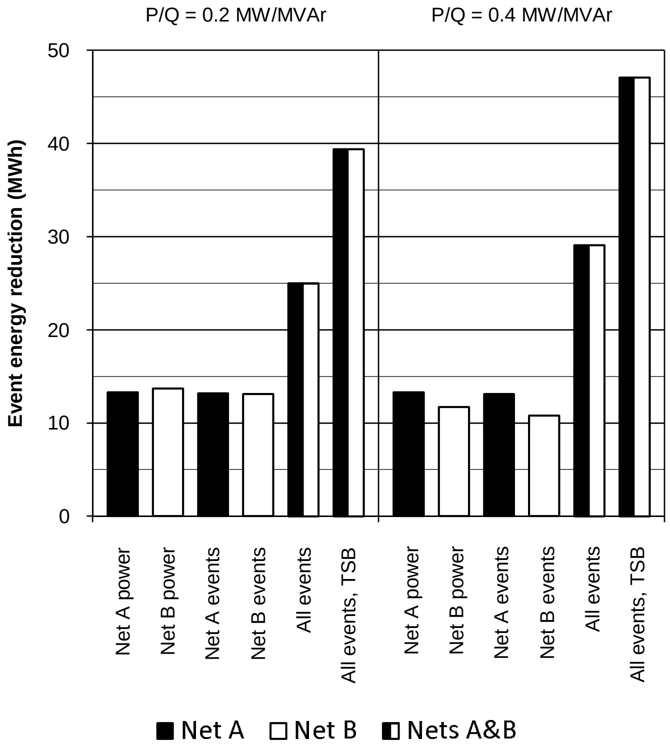

Figure 7: Reduction in event energy depending on configuration of simulation and converter rating.

Network	Voltage deviation	0.2 MVAr				0.4 MVAr			
		Single event	Single net	All events	All, TSB	Single event	Single net	All events	All, TSB
A	Over (%)	0.37	0.37	0.37	0.37	0	0	0	0
	Under (%)	-0.13	-0.37	-0.37	-0.37	0	0	0	0
B	Over (%)	0.30	0.30	0.30	0.30	0.09	0.09	0.09	0.09
	Under (%)	-0.17	-0.10	-0.33	-0.33	0	0	-0.33	-0.33

Table 2: Voltage deviation in per cent from target band depending on configuration of simulation and converter rating.

6. Conclusions

A simulation environment has been developed at Durham University that enables multiple types of network event to be monitored and acted on simultaneously. Network conditions are recreated from historical data by load flow analysis and an assessment is made on the applicability of an intervention from the ESS. This was a response to the need to evaluate the use of an ESS to act on a combination of objectives in a versatile manner. The simulations conducted within this simulation environment have shown that operating an ESS embedded in the distribution network has a positive impact on the tasks of voltage control and power flow management. The selection of events requiring an intervention and corresponding actions has been reached through analysis of the network behaviour before the addition of an ESS. Events were defined to generate a quantity of occurrences suitable to exercise the capabilities of the ESS, yet without being unreasonably difficult to resolve.

The decision made to locate the field trial ESS at a normally open point between two feeders has allowed multiple events to be tackled on multiple networks. Benefits greater than the sum of the parts have been accrued across the control objectives defined in this study. A single device operating to improve conditions on two networks has been shown to be more effective than two devices working in isolated networks. Care must be taken in extending this result to other networks, as differences in the temporal pattern of network use are a significant factor. To achieve an improvement over the case of a single isolated network, simple forecasting has been incorporated into the control algorithm. Greater gains are achieved in a multi-network configuration when operating with comparatively higher power flows.

ESS operation to improve the events of voltage deviation, reverse-power-flow and over-power has been shown. It is straightforward to expand the simulation to include any event that can be represented in the network model. An arbitrary collection of events will have a series of interconnected dependencies, conflicts and synergies. Requests that the events place upon ESS resources must be evaluated to understand how event complementarity can be best dealt with in the control algorithm design. Choices have to be made on how to ration the use of both the power and energy ratings of the ESS. The simulation techniques that have been developed can assist in the formulation of operating strategies to allocate transfers of real and reactive power.

It is impractical to install an ESS that is capable of providing a solution to all events at all times; either the events would have to be very modest or the ESS very large. The ESS operates to make a contribution to improving network performance in cooperation with other Smart Grid control actions such as active generator curtailment or demand side management. The proportion of contribution made by energy storage depends upon the event definitions and the varying behaviour of the network on both short and long timescales. A higher power rating and energy capacity ESS could solve a greater number of problems but there is a balance of cost/benefit to be achieved. The most successful strategy presented for this network for a device with a capacity of 0.2 MWh and power rating capable of 0.4 MW and 0.4 MVAr solved 2023 out of the 2979 events defined for this simulation exercise. Leaving the power rating the same while doubling the capacity to 0.4 MWh solves a further 91 events, doubling again to 0.8 MWh solves a further 56 events. These diminishing returns suggest that for the events considered here it may be difficult to construct a compelling business case for the installation of a device with sufficient capacity to respond under all contingencies. However, this would depend upon the value to the DNO associated with removing these events and the relative cost of competing solutions.

To establish a business case for energy storage ownership, a thorough understanding of the areas in which value can be brought is required. The first step in this process is to evaluate the technical benefits that can be achieved. These benefits must then be attributed to all of the stakeholders in the electricity supply value chain. A picture of the economic value accrued across all of the stakeholders is then possible. The techniques developed in this work allow investigation of how different modes of operation will change the relative success of each technical benefit considered, and therefore inform the overall economic value that will be achieved in each case. This knowledge has direct consequences for the technical and commercial policy of the ESS operator (in this field trial this is the DNO) but must also be recognised by ESS manufacturers, governments and regulators in their policy development.

Although this analysis has been carried out on an 11kV distribution feeder, there are observations that can be carried through to both higher and lower voltage levels. It is anticipated that plug-in electric vehicles (PEVs) will become widespread over the coming decades. If aspects of the battery management system are made available to the distribution network control system, then a massive opportunity opens up for highly distributed electrical energy storage at the lowest voltage level (230V) in the network. Network operators would be able to influence the scheduling of charging operations and even call on the batteries of PEVs to provide power to the network as long as suitable agreements are in place between vehicle and network operators. The development of a multi-agent system to coordinate similar tasks has been investigated by Lyons et al. (2010). If suitable control systems are put in place, similar opportunities for network control to those presented in this work become available, without the need to install a dedicated energy storage plant. On the other hand, moving up the voltage levels to 33kV, 66kV and 132kV where power flows are greater implies the installation of a much larger storage device. This would open up further possibilities for bringing benefits to network operation and begins to make it feasible to operate in short-term energy markets and thus provide further value to ESS ownership. The techniques that have been developed in this work are capable of assessing the benefits of energy storage at locations in the higher voltage network.

Significant changes to the methods used to control distribution networks will result from the transition to the Smart Grid. Electrical energy storage is one of the tools that will become increasingly available to network planners and operators. Greater visibility of the system state is necessary to enable sophisticated interventions that respond to network conditions remote from the point at which the ESS is located. To achieve the greatest benefits from the operation of an ESS, installation must be part of a broader smartening of the network with instrumentation and control equipment. As progress is made in the transition to future electricity networks, electrical energy storage embedded at distribution level is set to become an integral part of the Smart Grid.

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